An Effective Method for Modelling Non-Moving Stagnant Liquid Columns in Gas Gathering Systems

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Abstract
Gas gathering system modelling is often complicated by the presence of localized pressure losses that are not easily explained by traditional pressure loss correlations. The tendency is to assume the pressure loss correlation must be tweaked to match measured operating conditions. This often leads to inappropriate manipulation of tuning factors (efficiency factor or roughness).

A more appropriate approach is to recheck the validity of the input data and, most importantly, visit the field prepared to gather additional data to resolve the causes of the localized pressure losses. The objectives of this paper are to discuss one of the causes of localized pressure losses—Stagnant Liquid Columns—and to present several cases where localized pressure losses were interpreted to be caused by stagnant liquid accumulations.

Introduction
The maturation of the gas gathering systems throughout North America has resulted in the majority of systems being operated well below their original design conditions. Consequently, it is common to encounter pressure losses that exceed those predicted by steady-state single-phase and two-phase correlations. The reasons for these pressure losses are varied and most often relate to measurement issues, poor understanding of the pipeline and facility connections and sometimes non-moving liquid accumulations called stagnant liquid columns. Liquid accumulations are a concern because their continuous removal is difficult and they increase backpressure for all upstream wells, which reduces well deliverability and can result in localized pipeline corrosion.

One would think that the traditionally used steady-state two-phase pressure loss equations would be capable of predicting the pressure loss that occurs in these liquid accumulations. However, the steady-state flow of fluid must be, by definition, continuous: inlet rate equal to outflow rate. If the liquid enters the conduit and accumulates while the gas continues through, we no longer have steady-state flow and the validity of the correlation no longer holds.

It has been the authors’ experience that localized pressure losses are often associated with liquid accumulations. Typically, field staff usually know there is a problem and may or may not have already realized that it is due to liquids, but it is usually a surprise for head-office staff because there is little or no liquid production reported.

This leads to the question, how do we reliably identify stagnant liquid columns and how should they be modelled? To answer this question, a discussion of recommended modelling procedures is required.

Discussion
Pressure Loss Categorization
The existing steady-state pressure loss correlations generally do a very good job of estimating pressure losses when used appropriately. Consequently, a comparison of simulated line pressures with field measured line pressures should result in a reasonable match within a preset tolerance. Measured line pressures that do not match modelled line pressures must be scrutinized closely to determine the cause of the mismatch, rather than relying primarily on tweaking tuning factors such as pipeline roughness or flow efficiency.

For wells or groups of wells where a reasonable match is not initially obtained, it is good practice to begin by attempting to classify the unmatched pressure losses as either a systemic or localized step pressure loss problem before making changes to the model to force a match.

Systemic pressure losses manifest as a gradual or cumulative degradation in the match as you look further upstream from the model start point (point where a flowing pressure is a given). Systemic pressure loss problems are always due to incorrect pipeline specifications, the presence of too much fluid (gas and liquid), the presence of too little fluid or the specification of an inappropriate pressure loss correlation.

Step pressure losses manifest at a point in the pipeline system where all wells downstream of that point match within the preset tolerance, and all wells upstream of that point exhibit a consistent step increase in pressure over that predicted by the pressure loss correlation. Step pressure losses are usually friction-based if associated with a plant inlet or header, and are usually hydrostatic-based if located in a pipeline between wells.

Since total pressure loss is largely the sum of the friction and hydrostatic pressure loss, it is also good practice for modellers to get into the habit of classifying every step pressure loss as either friction-dominated flow or hydrostatic-dominated flow. Since hydrostatic pressure loss is governed by Equation (1):

\[ \Delta P_s = \rho gh \]  

we can assume hydrostatic pressure losses can be represented as fixed pressure loss. Obviously, this is an approximation as the density of a two-phase mixture depends upon the proportions of gas and liquid.

For single-phase flow, the Fanning correlation, as shown in Equation (2), governs friction pressure loss:

\[ \frac{f}{D} = \frac{0.079}{Re^{0.25}} \]
\[ \Delta P_j = \frac{f p v^2 L}{2 g D} \]

Since friction pressure loss is a function of the square of the gas velocity, friction pressure loss increases non-linearly with respect to gas flow rate.

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![Figure 1: Pressure loss due to friction (Fanning).](image)

Figure 1 presents an example of the friction pressure loss vs. gas flow rate for a pipeline. Note that changing the pipe roughness has very little impact on pressure loss at low gas rates [less than 14 \(10^3\) m\(^3\)/d (500 Mscfd)] for this example, but has a dramatic effect on pressure loss for high gas rates. It is obvious that attempting to use the friction-based tuning factors (roughness or efficiency) to tune a low flow rate pipeline is not advisable. A solution can sometimes be forced with the overuse of roughness or efficiency, but the result is usually a model that can reproduce only current conditions. These models invariably fail when simulating before and after conditions for field modifications that significantly change gas flow rates or operating pressures.

The same argument applies to two-phase flow since all two-phase correlations utilize a modified form of Fanning or an approximation of Fanning. The main difference being that the procedure begins with the calculation of liquid holdup that is then used to calculate a two-phase friction factor, a two-phase density and a two-phase velocity.

![Figure 2: Example of a pressure loss step change.](image)

Figure 2 presents one pipeline leg of a gas gathering system. Each well in the leg displays the well name, model calculated line pressure and measured line pressure. Note that working outward from the plant, the calculated and measured line pressure for the wells 02-10, 11-02 and 06-01 all match very closely. Also, note the calculated and measured line pressure for the wells 06-27 and 06-36 differ by 855 kPa (124 psi) and 786 kPa (114 psi), respectively.

Since the line pressures for the first three wells (02-10, 11-02 and 06-01) all match closely and the next two wells differ by very similar values, it is deduced that the difference in calculated and measured line pressures at the wells 06-27 and 06-36 is most likely a localized step pressure loss problem. The location of the problem(s) could be at each well site, in the tie-in pipelines or in the common pipeline that ties into the well 11-02 location with its endpoints labeled A and B. It is deduced that the pressure loss most likely occurs in the link between points A and B, since this is the simpler solution.

Although the problem identified could be a partially closed valve, an undersized component in a header or some form of plugging, our experience has been that most instances are due to the build up of liquids in a significant topographical depression. Examples of this would include steep-sided valleys, coulees and sometimes river crossings.

The preceding summarizes the basic methodology recommended for diagnosing potential reasons for unmatched pressure losses. The diagnosis process must not stop at this step. Additional information must be gathered to prove or disprove the hypothesis and a field trip must be conducted to confirm the findings.

Three main issues must be dealt with when making the diagnosis of liquid accumulations in a pipeline system. First, the two-phase pressure loss correlations should predict the measured pressure loss. Second, pipeline pigging should remove all of the liquids. Finally, liquids production or liquid condensation in the pipelines must be reported.

In the case of two-phase correlations, it is common for a modeller to include elevation profiles and add produced liquid rates, but still not be able to match the measured pressure loss. In these cases, careful review of the liquid production reports reveal that there are usually periods of no liquid production after a slug is produced or after a pig has been run through the system. Liquid production re-commences only after the liquid traps have sufficiently refilled such that liquids can be carried over the spill-point.
In the case of pipeline pigging, the pigging efficiency rarely approaches 100%, and since pigging is not generally a continuous process, the liquid traps usually re-fill quickly since liquid production is continuous.

In the case of liquid production reporting, it is common practice to only report water production if it exceeds a certain volume per reporting period. Water production from condensation is rarely reported, since the volumes are generally low and condensed hydrocarbon liquids are often reported as a gas equivalent volume.

For these reasons, it is important to first concentrate on identifying the locations where extra pressure losses occur over and above that predicted by the model. It is useful to categorize those pressure losses as systemic or step loss, and to identify if the loss is probably friction- or hydrostatic-based. Finally, it is paramount that the modeller goes to the field to discuss the problem areas with field personnel and measure or oversee the measurement of additional pressure data in the problem sections of the pipeline system. This will ensure that all pressure loss match problems are categorized and modelled correctly.

Knowledge From Wellbore Liquid Load-up

A way to deal with liquid accumulations was derived from work in wellbores. Gas wells have long been the subject of liquid load-up studies. Turner et al.\((1)\) developed an equation based on a droplet model that is relatively accurate in calculating the critical gas flow rate below which liquid load-up will occur.

Coleman et al.\((2,5)\) added a series of papers that describe the physical processes that occur in well load-up. Key points included in Coleman et al.’s description of the load-up phenomenon are that liquid production ceases, condensation can be a major contributor to liquid load-up and the terminal event has gas flow percolating through a liquid column and then continuing up to the wellhead in single-phase gas flow. The increased backpressure caused by the liquid head is much greater than the fluid load experienced prior to load-up, and so sandface flowing pressure increases significantly causing gas flow rates to decrease dramatically.

Liquid production initially ceases, but gas continues to flow at much lower values than experienced prior to liquid load-up. Liquid production is sometimes subsequently reported, but this is usually due to periodic natural unloading, stop cocking by the operator or use of a plunger lift system.

Parallels – Pipelines and Wellbores

There are strong similarities between a liquid-loaded wellbore and a liquid-loaded pipeline. Where liquids are present and gas flow rates are high, both can be modelled successfully using two-phase correlations. However, as gas flow rates decline, both experience holdup of the liquids such that the flow of liquid ceases for periods of time and both require mechanical methods to remove the liquid accumulation.

Use of a Stagnant Liquid Column

Stagnant liquid columns can occur in systems where there is no apparent liquid production and in systems with known liquid production. Regardless, this technique should only ever be used if the following tests are passed. The current rules employed are:

1. There must be a significant localized pressure loss over and above that predicted by the pressure correlations. This is also often identified in gathering systems as a step change in pressure.
2. There must be a creek, river crossing or some place where the liquids must first flow downhill and then flow uphill. The uphill angle should be at least a 20 degree above horizontal.
3. The velocity of the gas is insufficient to move the liquids effectively, as determined from Turner et al.’s chart (Figure 4) as modified for pipeline systems.
4. The measured pressure step change must not exceed 6 kPa/m (0.265 psi/ft) × h, where h is the uphill flow elevation change.

Example Cases

Example 1

This example was introduced in Figure 2, and it was concluded that the pressure loss is a step loss. Since the calculated line pressures are approximately 827 kPa (120 psi) lower than the measured values for both these wells, it has been concluded that the step loss is most likely in the common pipeline from the well 11-02 to the common header for the wells 06-27 and 07-36, labeled A – B. A check of topographic maps (not included) indicates this section of the pipeline crosses a valley with sides that sharply rise 500 feet from the valley floor. No liquids production is reported from the valley floor, and there must be a step change in pressure.
wells 06-27 and 07-36, but discussion with the operators indicate that the presence of liquids is likely.

The superficial gas velocity for the pipeline segment A – B shown in Figure 2 is less than 0.3 m/s (1 ft/s). From Figure 2, it can be seen the lowest pipeline operating pressure is just over 3,447 kPa (500 psia) and the highest operating pressure is approximately 4,137 kPa (600 psia). Although these pressures are higher than the scale shown in the modified Turner et al. graph shown in Figure 4, it is clear that gas velocity of 0.3 m/s (1 ft/s) is very close to or below the lower line indicating liquids will accumulate and steady-state two-phase flow will not occur.

Consequently, a fixed pressure loss of 827 kPa (120 psi) is added to the model between A – B, shown in Figure 5, to model the hydrostatic nature of this pressure loss. The calculated line pressures at the wells 06-27 and 07-36 now match the measured line pressures quite closely. This method replicates the pressure
loss behaviour commonly experienced when gas flow rates change in pipeline segments operating well below their flow capacity.

If this pipeline segment had been matched using friction-based tuning methods, then any increase in gas flow rate would have result in an extremely large increase in pressure loss in the pipeline, and any decrease in gas flow rate would result in a large decrease in pressure loss. The authors have never modelled a pipeline segment where small changes in gas flow rate resulted in large swings in pressure loss in pipeline segments operating well below their flow capacity.

Example 2

Figure 6 presents another case where a stagnant liquid issue requiring a 372 kPa (54 psi) pressure loss was identified. In this case, the operator argued that the line had been pigged and was dry. On further questioning, it was determined that the line was last pigged several years previously. The line was subsequently pigged and a large volume of hydrocarbon condensate was recovered. Total gas rates from upstream wells also increased by over 28.31 m$^3$/d (1 MMscfd).

Example 3

Figure 7 presents a case run using a single-phase correlation. Comparison of calculated and measured line pressures demonstrates there is no match. It is known that liquid production is occurring in this system. A check on gas velocities [generally > 6 m/s (20 ft/s)] indicates that the use of a two-phase correlation and the input of appropriate elevation changes may resolve the match.
Figure 8 presents the same case after the input of liquid rates, the input of elevation changes and the switch to a two-phase correlation. The match is much improved and considered reasonable given the accuracy of the measurements. A field trial may serve to tighten this match.

Conclusions

A modelling process has been outlined that simplifies the modelling of pipelines systems by stressing the categorization of measured pressure losses as systemic or step loss and then into friction-based or hydrostatic-based. Issues identified by this process are then resolved via a targeted field trip by the modeller.

In cases where very little liquid or no liquid production occurs, an important cause of pressure loss is stagnant or non-moving liquid columns that are not handled by current pressure loss correlations. It is recommended that, once confirmed, liquid accumulations can be reasonably modelled as fixed pressure losses.

The method of stagnant liquid columns is a definite improvement on the tendency of modellers to use friction-based tuning methods to match measured pressure losses, even though it is an approximation. Further work needs to be done to more accurately describe the phenomenon of stagnant liquids and to explain its impact on gas gathering system analysis.

SI Metric Conversion Factors

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<tr>
<th>Unit</th>
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<tr>
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<tr>
<td>ft</td>
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<tr>
<td>psi</td>
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<tr>
<td>bbl</td>
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<td>MMscfd</td>
<td>× 28.317 = m³/d</td>
</tr>
<tr>
<td>ft/s</td>
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NOMENCLATURE

- \( D \) = pipeline internal diameter
- \( g \) = gravitational constant
- \( h \) = vertical height of fluid column
- \( L \) = length of pipeline
- \( v \) = fluid velocity
- \( f \) = Fanning friction factor
- \( \Delta P_f \) = friction pressure loss
- \( \Delta P_h \) = hydrostatic pressure loss
- \( \rho \) = fluid density

REFERENCES


Further Reading

2. MATTAR, L. and ZAORAL, K., Gas Pipeline Efficiencies and Pressure Gradient Curves; paper No. 84-35-93 presented at the 35th Annual Technical Meeting of the Petroleum Society of CIM, Calgary, AB, 10-13 June 1984.

Authors’ Biographies

Ralph McNeil has been with Fekete since 1987, where he worked in reserve evaluations and pipeline optimization before assuming the role of Senior Technical Advisor responsible for the development of F.A.S.T. Piper™. He has taught the F.A.S.T. Piper™ course for over 10 years and is well practiced in converting complicated pipeline problems into manageable, solvable components.

Dave Lillico has been with Fekete since 1989, where he worked in reserve evaluations until 1999 at which time he assumed the role of manager of the Pipeline Optimization group. Dave has been involved with modelling all aspects of gas flow from the reservoir through the wellbore, pipelines and compression. Dave has modelled gathering systems throughout North America, Australia, Bangladesh, Tanzania and Turkey. The pipeline modelling group that Dave supervises is responsible for modelling in excess of 15,000 wells/year.